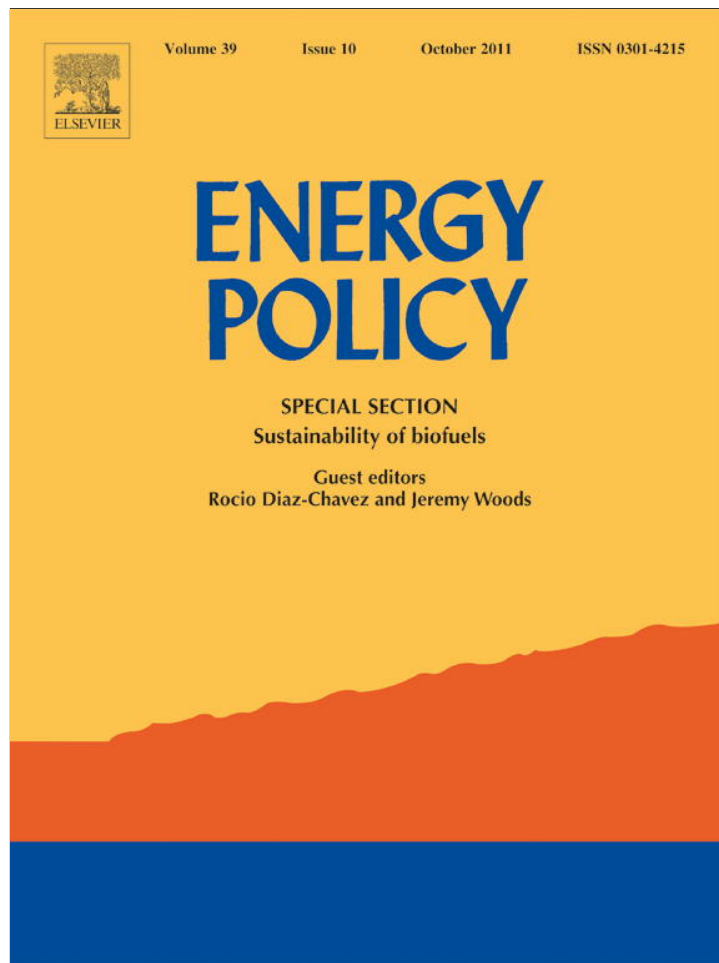


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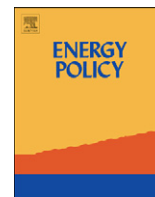


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Regulated electricity retailing in Chile[☆]

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ABSTRACT

While some countries have unbundled distribution and retailing, skeptics argue that the physical attributes of electricity make retailers redundant. Instead, it is claimed that passive pass through of wholesale prices plus regulated charges for transmission and distribution suffice for customers to benefit from competitive generation markets.

We review the Chilean experience with regulated retailing and pass through of wholesale prices. We argue that when energy wholesale prices are volatile and prices are stabilized, distortions emerge. Regulated retailers gain little by mitigating or correcting them. On the contrary, sometimes price distortions increase their profits. We estimate the cost of three distortions that neither regulated retailers nor the regulator have shown any interest in correcting.

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1. Introduction

Not so long ago electric utilities were thought to be vertically integrated natural monopolies and most were owned by governments. But during the last 20 years many countries unbundled generation, transmission and distribution and privatized their electricity sectors. In most cases generation has been liberalized and opened to competition and, while both transmission and distribution remain natural monopolies, price caps have dramatically changed the way in which they are regulated.

Sweeping reforms on the supply side sharply contrast with the few if any changes that residential and small commercial customers have seen. Despite of the technological revolution during the last decades, in most countries consumption is still measured with the same electromechanical induction watt-hour meter invented in 1894 by Oliver Schallenger, which is read manually and on-site once a month.² Consequently, almost all customers still pay a flat per kWh rate, which neither varies with the time of the day nor the season of the year. And, perhaps not coincidentally, they still buy electricity from the same local regulated distributor.

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² Until recently hourly metering was quite expensive. But today solid state meters, which can measure and record consumption minute by minute, cost around \$100. Moreover, advances in telecommunication technology allow smart meters to be monitored centrally.

The paucity of reform on the demand side is somewhat puzzling because the advantages of time-of-day and seasonal pricing have been known for a long time. Maybe for this reason, some link improved pricing and the unbundling of distribution (the natural monopoly) from electricity retailing, which can be liberalized. In a series of papers, Stephen Littlechild argues that deregulated retailers reduce the scope for government-induced price distortions³; allow prices to vary with the season and time of the day⁴; increase the likelihood that new and valuable services will be discovered and introduced⁵; and are arguably more effective than regulation in bringing retail prices closer to generation costs.⁶

Yet while some countries have liberalized electricity retailing, many remain skeptical. For example, Defeuilley (2009) argues that liberalization has failed to meet expectations of reduced barriers of entry due to customer choice, faster innovation and lower prices.⁷ More fundamentally, as the so-called spot price pass through proposal by William Hogan, Paul Joskow and Larry Ruff suggests, customers can in principle reap all the benefits wrought by competitive generation if the energy tariff charged by regulated distributors is a passive pass through of the wholesale spot market price, perhaps averaged every month.⁸ Consequently, the argument goes, unbundling adds little competitive pressure by itself and may

³ Littlechild (2002, 2009).

⁴ Littlechild (2002).

⁵ Littlechild (2002, 2009).

⁶ Littlechild (2000).

⁷ But see Littlechild's (2009) comment.

⁸ According to Littlechild (2000) the earliest written statement of this proposal appeared in Hogan's comments to the California PUC and the House Energy and Power Subcommittee in Washington in 1994, which are referred to as the California Blue Book proposals. An early published statement is in Garberet al. (1994), and later in Ruff (1999). Joskow's views are in his 2000 paper. Joskow (2008) is still skeptical of the usefulness of liberalized retailers.

even hurt customers if retailers enjoy some market power or spend resources in marketing and sales efforts.⁹ Worse, Joskow (2000b) argues that the physical characteristics of electricity renders irrelevant many of the costly services typically provided by retailers in other industries—regulated retailing seems a better way of selling electricity. He argues that retailers should concentrate in providing value-added services such as risk hedging, real-time metering and control or green power.

In this paper we take a close look at regulated retailing, as it has been practiced in Chile for almost 30 years. Chile was a pioneer in electricity reform. The 1982 electricity law functionally separated generation, transmission and distribution, introduced mandatory marginal cost dispatch, opened access to transmission lines, created a contract-based generation market and formalized price cap regulation of distribution.¹⁰ More important here, it introduced regulated retailing: distributors purchase energy and capacity to generators under long-term, regulated contracts and resell it to residential and commercial customers at regulated prices. Regulated tariffs pass through the expected marginal cost of generating energy and power. As we explain in Section 2, this setting is close to ideal to realize the hallowed advantages of regulated retailing. Yet we show that the regulated price system has significant and costly deficiencies, which regulators have been either slow or incapable to correct.

We observe that regulated retailing comprises both the pass through of the wholesale price and a specific allocation of price risk among generators and customers. Then the tradeoff is this: on the one hand, when customers pay the short term wholesale price they confront efficient signals to consumption and energy outages are prevented almost automatically; on the other hand, if generators and customers are risk averse, price volatility is costly for both. Any regulated retail regime entails choosing a point on this tradeoff, but when prices are stabilized, distortions emerge. And, as the Chilean case suggests, regulated retailers gain nothing by mitigating or correcting those distortions, because they just pass through wholesale prices. Worse, sometimes price distortions increase distributors' profits. Thus, while not necessarily proving the case of liberalized retailing, these deficiencies cast doubt on the basic premises of spot price pass through proposal and on the practical feasibility of efficient pricing with regulated electricity retailing.¹¹

2. Regulated retailing in Chile

2.1. Vertical structure and regulated retailing

Fig. 1 schematically describes contract flows in the Chilean system. The core of the price system is the so-called spot market. In order to minimize the system's operation cost, the Economic Load Dispatch Center (CDEC by its Spanish acronym) centrally dispatches plants according to strict merit order to meet load at every moment. The system's marginal cost is the running cost of the most expensive unit required to meet system load and changes every half hour. Dispatch is mandatory and completely independent of contractual

obligations. For this reason, each half hour a given generator is either a net supplier to the system or a net buyer. Net buyers pay net suppliers the system's marginal cost.

In addition, each generation unit is paid a monthly capacity payment based on its annual availability. The price of capacity equals the capital cost of the peaking technology, a diesel turbine (see below). An annual capacity balance is calculated for the system's peak hour, and generators with more capacity than their customers' load sell capacity to generators with a deficit at a set price.

The second echelon in Chile's system is transmission. Every four years the National Energy Commission (NEC), a government agency, fixes transmission charges for the use of the main high-voltage grid. These charges are partly paid by generators and partly by customers according with their expected use of the grid; use is calculated using GGDF and GLDF factors.¹²

Next, every four years NEC calculates the value added of distribution (VAD) combining an efficient-firm standard with yardstick competition.¹³ VAD is equal to the efficient cost of distributing one kW of peak capacity at maximum load, and is fully paid by customers.

Now the 1982 law introduced neither customer access to the wholesale market nor retail competition for small customers. Instead, it defined large customers – those who consume more than 2 MW, and small customers – the rest. Large customers, it was thought, can bargain supply conditions and tariffs with generators, and were left alone to sign free wholesale contracts. Each small customer, by contrast, pays regulated capacity and energy prices and is supplied by a distributor who has a legal monopoly, buys energy and capacity under a regulated wholesale contract and pays transmission charges on behalf of customers. Therefore, distributors develop and maintain the medium- and low-voltage grid – the wire business, and deliver electricity to regulated customers inside their concession area – the retailing business.

2.2. Prices paid by customers

2.2.1. Large customers

Customers who demand more than 2 MW buy their electricity directly from generators and pay unregulated market prices for energy (p_e^m) and capacity (p_c^m). They must also pay a per-kWh transmission charge τ_i . Thus, if customer i consumes E_i kW and her load during the peak hour is D_i , her total bill is

$$E_i(p_e^m + \tau_i) + D_i p_c^m. \quad (2.1)$$

These prices are typically set by competitive tender. Because most unregulated customers are directly connected to the transmission grid, they pay no distribution charge.

2.2.2. Regulated customers

Customers who use 2 MW or less capacity pay regulated prices for energy (p_e^r) and capacity (p_c^r). In addition, they must pay their share of the value added of distribution and a per kWh transmission charge, τ . Hence, customer's j total bill is

$$E_j(p_e^r + \tau_j) + D_j p_c^r + VAD_j. \quad (2.2)$$

Node prices p_e^r and p_c^r are set by NEC every April and October.

Now in 1982 hourly metering equipment was very expensive and an energy-only tariff was designed for residential and commercial customers. Thus to transform the per-kWh capacity charge into an energy charge, a load-coincidence factor ψ is

⁹ This is a direct consequence of a result first stated by Spengler (1950). If transmission and distribution charges are regulated, and generation is competitive, then vertical integration of distribution and retailing is irrelevant. Worse, if the liberalized retail segment is not perfectly competitive, consumers lose with liberalization as they have to bear the margin wrought by market power. See Galetovic and Sanhueza (2009) for a formal analysis.

¹⁰ On Chilean reforms see Arellano (2007), Bernstein (1988), Fischer and Serra (2000), Galetovic and Muñoz (2006), Moya (2002), Raineri (2006), Rudnick (1994) and Rudnick and Donoso (2000).

¹¹ For another critical assessment of the spot price pass through proposal, see Littlechild (2000, 2003).

¹² See Galetovic and Muñoz (2006).

¹³ See Bustos and Galetovic (2007) and Rudnick and Donoso (2000).

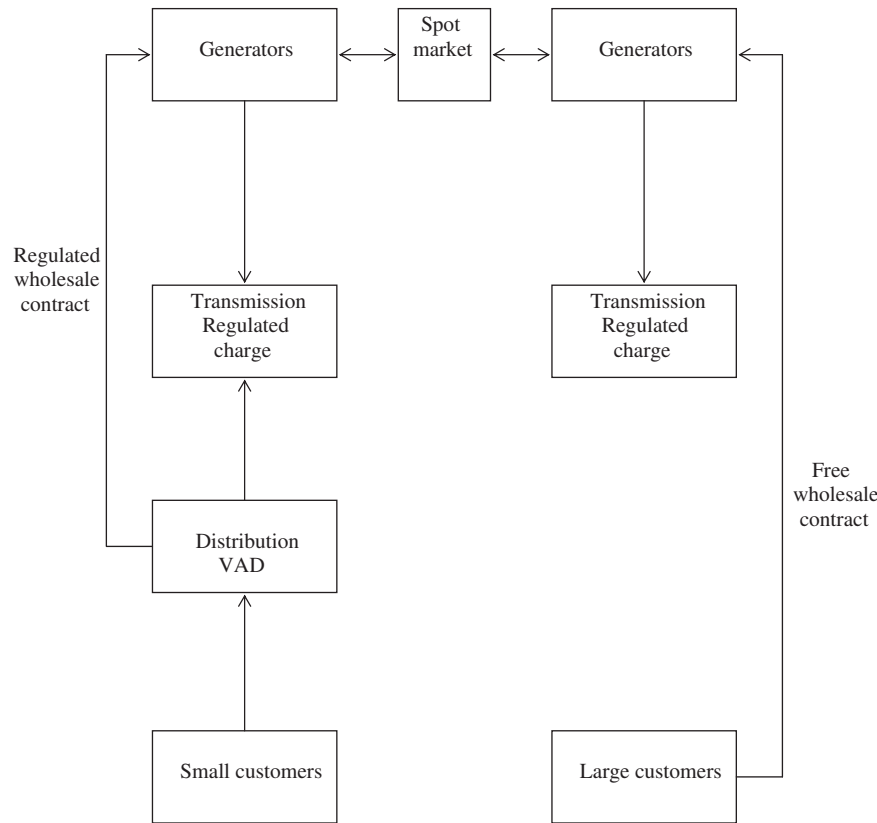


Fig. 1. Regulated retailing in Chile (flow of payments).

estimated. Similarly, to transform the per-kW VAD charge a so-called responsibility factor δ is used. The total bill of a customer with an energy-only meter is thus

$$E_j(p_e^r + \psi p_c^r + \tau_j + \delta VAD_j), \quad (2.3)$$

where the term in parenthesis is the so-called BT1 tariff.

2.2.3. Node prices

As can be seen from Eqs. (2.1)–(2.3), regulated prices are determined by the node prices. How are these set?¹⁴ Begin with the energy node price. Let $E(t)$ be the energy projected to be consumed at time t , $mc(E(t))$ be the system's marginal cost at time t , given $E(t)$ and ρ the real discount rate. Given these parameters p_e^r is the average price that yields exactly the same revenue in present value as generators would expect to obtain if they would sell their energy at the system's marginal cost over the next 48 months, viz.

$$p_e^r \int_0^{48} E(t)e^{-\rho t} dt = \int_0^{48} mc(E(t); h)E(t)e^{-\rho t} dt; \quad (2.4)$$

hence

$$p_e^r = \frac{\int_0^{48} mc(t; h)E(t)e^{-rt} dt}{\int_0^{48} E(t)e^{-rt} dt}.$$

The capacity node price equals the cost of investing in a diesel-fired turbine meant to run at the system's peak hour. This cost equals the sum of I_t , the cost of the turbine, and I_l , the cost of the transmission line needed to connect it to the high-voltage grid. Both are brought to a yearly equivalent assuming an 18-year recovery period, a system reserve margin, η and a 10% real

discount rate. Thus

$$p_c^r = (1 + \eta) \frac{1}{R} (I_t + I_l) \quad (2.5)$$

with

$$R \equiv \left[\int_0^{18} e^{-0.1t} dt \right]^{-1}$$

In principle, energy and capacity node prices are directly passed through to customers. Nevertheless, when the electricity law was designed in the early eighties, regulatory discretion was restrained by forcing the energy node price to lie within a band determined by unregulated market prices.¹⁵ Hence, the energy node price was restricted to vary within a band whose limits were determined by market prices paid by large customers.

It is important to note that both the model used by NEC to calculate the energy node price and the model used by CDEC to operate dispatch solve the same optimization problem, with essentially the same data. The only difference is that CDEC's model uses a finer partition of loads and months than NEC's. Moreover, CDEC voluntarily uses the regulated capacity price p_c^r to value capacity transfers among generators.

2.2.4. Regulated pass through of the expected spot price

Expression (2.4) shows that the energy price paid by regulated customers is linked to the wholesale or spot price. Nevertheless, some argue that in Chile regulated retail prices do not pass through the wholesale price of energy because the node price equals the expected long-run marginal cost of energy over the next four years, not actual spot prices. Worse, because only generators exchange energy in the spot market and dispatch is

¹⁴ See Galetovic and Muñoz (2009) for details.

¹⁵ See the appendix in Galetovic and Muñoz (2009) for details.

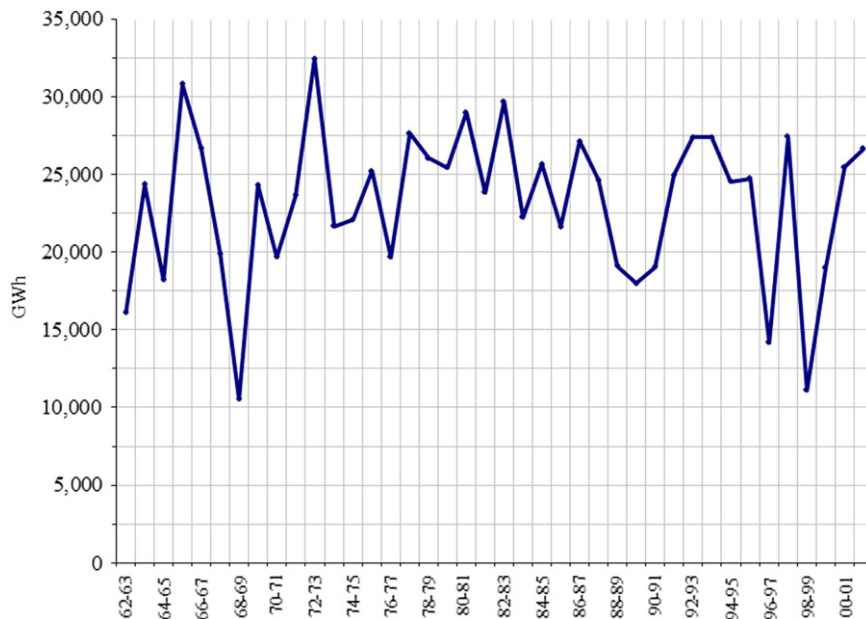


Fig. 2. Flow of hydro energy available in SIC (in GWh, 1962–1963 through 2001–2002).
Source: CDEC-SIC

mandatory, it is sometimes claimed that the term spot market is an oxymoron—in a market, so the argument runs, wholesale customers directly bid and buy energy at the spot price.¹⁶

This description of the Chilean market overlooks three facts. One is that the 1980s reforms started from the premise that generators would sell electricity to large customers through long-term contracts. Hence, contract prices smooth out the hourly, daily and seasonal variation of the marginal cost of energy (see Fig. 2). It is also the case that any generators' opportunity cost of energy and capacity is always given by the spot price, a direct consequence of mandatory marginal cost dispatch. Hence, even contracts with large clients, which represent about 40% of energy sold and are completely free, must reflect expected marginal costs in equilibrium. Consequently, the rule used to set regulated energy and capacity prices just follows the logic of a competitive contract market. Last, entry into generation is free, hence expected spot prices must be high enough to pay for operation and investment costs in equilibrium. In other words, free entry and the resulting composition of generation plant determines average spot prices.

More fundamentally, the volatility of wholesale prices implies that regulated retailing comprises both the pass through of the wholesale price and a specific allocation of price risk among generators and customers. One possibility is, of course, for customers and generators to bear price risk. Another is to smooth out price volatility and exchange energy at a stabilized price—the Chilean solution. But whatever the choice, the tradeoff is this: on the one hand, when customers pay the short term wholesale price they confront efficient price signals and energy outages are

prevented almost automatically; on the other hand, if generators and customers are risk averse, price volatility is costly for both.¹⁷ Chile's regulated contract is one among many possible choices for a regulated retail contract; and generally speaking, any regulated retail regime entails choosing a point on this tradeoff.

2.2.5. Recent changes

In response to the Argentine gas cuts (see below) the law was amended in 2005 and auctions for long-term regulated contracts substituted for the node price.¹⁸ Thus, in new contracts the regulated energy tariff paid by customers will be the winning bid—the price of capacity will still be calculated with formula (2.5). Moreover, over the life of the contract, which lasts at least 10 years, tariffs will be adjusted following an exogenous indexation rule.

While bids substitute for regulated prices, the characteristics of the contract and the implicit risk allocation remain essentially the same. Moreover, it can be shown that in a competitive market bids should equal the expected marginal cost of energy. Hence, as far as our analysis of regulated retailing goes, little changes.

2.3. Resource availability and price volatility

We end this section with a description of resource and price volatility in Chile. While there are four disjoint electricity systems in Chile, in what follows we consider only one, the Central Interconnected System (SIC by its Spanish acronym). In 2009 SIC covered around 93% of Chile's population and comprised around 70% of its total installed capacity.

52.3% of SIC's capacity (9385 MW) and about two thirds of the energy generated on average come from hydro plants. Nevertheless, water availability is volatile. Fig. 2 shows the amount of hydroelectric energy that could have been generated with currently installed hydro power plants in each hydrological year between 1962–1963 and 2001–2002. As a benchmark, note that

¹⁶ For example, Joskow (2000a, 2000b), argues: what is generally referred to as a spot market in Chile is not really a market in the sense that the spot markets for energy in California, Norway, or England and Wales are markets. Indeed, it is little different from the centrally dispatched power pools like PJM that existed in the United States for decades before restructuring. Generators are dispatched based on estimates of their marginal production costs, and the marginal cost of the last supply unit called to meet demand determines the market clearing price. Network congestion and constraints are centrally managed by the system operator (the CDEC in Chile) in conjunction with the least-cost dispatch of generators. While this mechanism for dispatch and spot-price calculation gives generators incentives to keep their costs low and their availability high, it represents a simulated spot market for energy rather than a real spot market.

¹⁷ Neither Hogan, nor Joskow nor Ruff are very precise on what the exact frequency of spot market pass through should be, but they seem to imply that it should be the monthly average.

¹⁸ See Barroso et al. (2007).

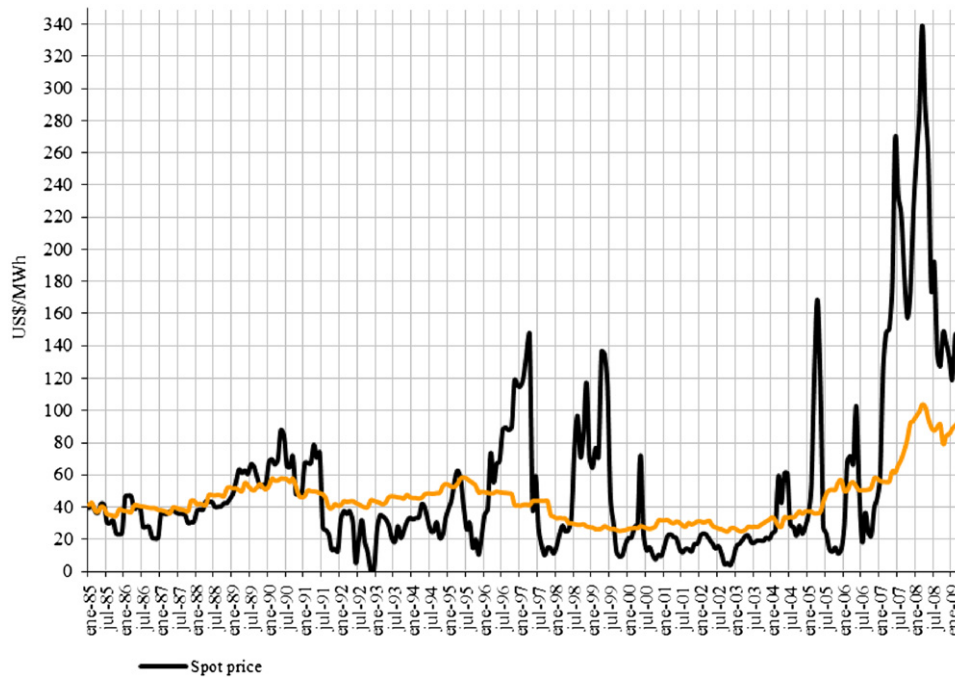


Fig. 3. Energy node and spot prices, 1985–2009 (in dollars of May 2009).

in 2007, 41,263 GWh of energy was generated. Hence, in a very wet year, such as 1972–1973, over 81% of generation can be supplied by hydroelectric plants.¹⁹ In an average year, hydroelectric generation can supply around 58% of generation (just over 24,000 GWh). But in a very dry year, such as 1968–1969 or 1998–1999, only a little more than 11,000 GWh, or roughly 27% of the quantity generated, is supplied by hydroelectric plants. In other words, in a very dry year nearly 13,000 GWh is lost—over half of the hydroelectric energy normally available or close to one-third of annual generation.

Hydro generation is complemented with natural gas-fired turbines (27.2% of installed capacity), coal (8.9%), diesel turbines (8.2%) and others (3.4%). The high share of natural gas reflects investments made between 1998 and 2004, when combined-cycle turbines fueled with imports from Argentina were massively installed. Consequently, the share of hydro generation in total capacity fell from 80% in 1993 to 52.3% in 2009. Nevertheless, in March 2004, due to an internal shortage caused by price ceilings, the Argentine government began to restrict natural gas exports and by 2007 these had almost dried out. In the aftermath, hydro generation and coal generation became profitable again, and combined-cycle turbines were made to run with diesel, which is more expensive.

Fig. 3 plots monthly node energy prices and average spot prices. It is apparent that customers bear substantially less price volatility by paying the node price instead of following the spot price—the coefficient of variation of the node price is about one-third of the coefficient of variation of the average monthly spot price.²⁰ Moreover, mainly because of draughts, the spot price may exceed the node price by a factor of up to five.²¹ Last, while the

node price is much less volatile, it ranges from \$24.78/MWh to \$103.75/MWh, and increased substantially in the aftermath of the Argentine gas cuts.

3. Some estimates of the losses wrought by regulated retailing

3.1. The Chilean price system during shortages

As said, regulated retailing entails a choice between smoothing price volatility and efficient short run price signals. In practice, regulators the world over have been loath to let customers bear volatility, so with regulated retailing either too much or too little electricity is used. Occasionally, however, energy consumption at the smoothed price exceeds physical availability, and then some sort of physical rationing becomes inevitable.

Chile's regulators anticipated this and designed an ancillary price system to deal with energy shortages. When a shortage occurs, NEC issues a rationing decree. The decree forces an equiproportional reduction of load upon each customer and forces generators to compensate regulated customers for all rationed energy. The per kWh rate of compensation equals the difference between average VOLL, assuming proportional rationing (which is calculated by NEC every five or so years) and the price of energy.

In principle compensations can replicate the allocation of energy with flexible pricing.²² The reason can be seen in Fig. 4. Let D be the demand for energy and assume that $E_r < D(p_e^r)$, i.e. the quantity of energy demanded at the regulated price p_e^r is less than available energy. If VOLL is set equal to $D^{-1}(E_r)$, then the opportunity cost of consuming an additional kWh is equal to VOLL and consumption is exactly equal to available energy.²³ Thus in principle the compensation mechanism replicates the outcome wrought by flexible prices.

¹⁹ The hydrological year begins in April and ends in March of the following year. The rainy season in central Chile runs from May through September. The thaw in the Andes mountains (where water is stored as snow) starts in October and ends in March.

²⁰ Note that monthly average spot prices underestimate the volatility of half hourly spot prices.

²¹ Proponents of the spot price past through proposal argue that most of the spot price volatility would be averaged out if customers are charged the average monthly price. This is clearly not the case in Chile.

²² See Serra (1997) and Diaz et al. (2000, 2001).

²³ A customer who consumes an additional kWh pays the node price p_e^r and foregoes the compensation equal to $VOLL - p_e^r$.

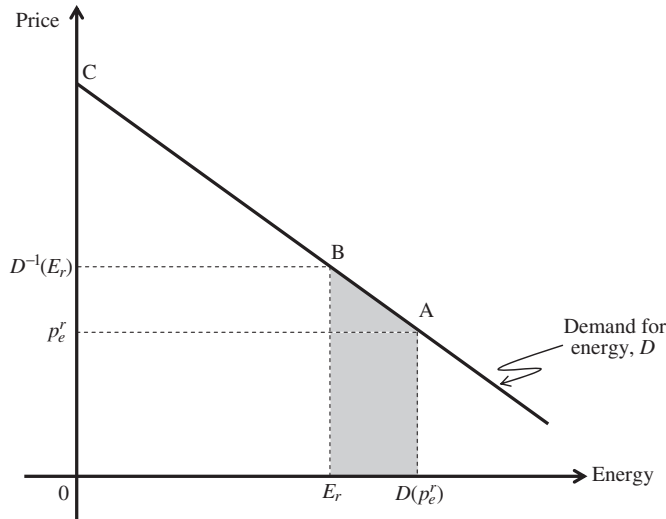


Fig. 4. Cost of shortages.

In practice, however, compensations are less flexible. To begin, NEC must estimate $D(p_e^r)$ and the amount of energy that is not supplied. So far it has assumed that it equals consumption during the previous year augmented by the expected growth rate of consumption—a rather noisy estimate. If the estimate is too small, generators pay in excess; if the estimate is too large, then much of the incentives wrought by compensations is lost. Second, NEC estimates an average of VOLL across aggregate customer categories – households, commercial and industrial – every four years. Hence, NEC's estimate ignores that outage costs vary substantially across customers within the same category, as was shown by Fierro and Serra (1997). Worse, it can be easily shown that average VOLL is higher than marginal VOLL, which should be used to calculate compensations (see below). Third, compensations are managed and paid through distributors who, acting on behalf of generators, have nothing to gain from making the mechanism work. Last, the duration of shortages does not coincide with meter reading cycles. Hence, periods when compensations are paid do not coincide exactly with actual shortages and sometimes regulators even extended it beyond the end of a drought.

The shortcomings of the compensation mechanism surfaced when a drought hit in 1998. Central Chile's rainy season runs from June to September; then snow melts in the Andes mountains and hydro plants run on runoffs between October and February. Now 1998 was one of the driest on record. Because after rains end runoffs can be estimated with precision, by September 1998 it was common knowledge that a drought would last until the next rainy season, which would begin no sooner than June 1999. This was ideal to make compensations work, because load reductions would be needed for at least nine months. But regulators did not apply compensations until June 1999. By then, however, they were useless because it was already raining again.

With no price signals, physical rationing was inevitable and protracted, nationwide outages occurred in November 1998 and between April and June 1999. Data collected by Fischer and Galetovic (2003) shows that the deficit was modest all the same. While monthly consumption was about 2000 GWh, only 450 GWh were rationed during the entire nine month period—about 2.5% of total energy consumption, or about 6% of residential consumption. Because water can be stored in the Laja reservoir, which has inter annual regulating capacity, modest reductions in consumption spread over the nine months would have been enough to prevent outages.

Power outages are the costliest way of rationing. At the other extreme, prices that match demand and supply are the efficient

way of doing it—the cost of such rationing is the value of lost energy. In between is what Chile's electricity mandates, proportional rationing of each customer. In what follows we first calculate the cost of the 1998–1999 power outages and then the cost of the shortage had it been managed with prices. The difference is a measure of the potential benefits of liberalized retailing.

To obtain an estimate of the cost of the 1998–1999 outage, we use average VOLL. Average VOLL is estimated to be \$492.6/MWh in Chile. Hence, the cost of proportional rationing would have been about

$$450,000 \text{ MWh} \times \$492.6/\text{MWh} = \$221.67 \text{ million.}$$

This is a lower bound estimate of the cost of outages because it assumes that all users reduce their consumption proportionately and no outages are necessary.²⁴

An efficient restriction, by contrast, sheds those loads that are valued the least, and it costs

$$\int_{E_r}^{D(p_e^r)} D^{-1}(E) dE,$$

or area $D(p_e^r)ABE_r$ in Fig. 4. Now define $\Delta p \equiv D^{-1}(E_r) - p_e^r$, i.e. the increase in price such that the amount of shedded energy equals the deficit. With the methodology developed by Galetovic and Muñoz (2009) we use the estimate of the short run price elasticity of the residential demand for energy by Benavente et al. (2005a) to quantify the effect on energy consumption of raising the BT1 residential tariff by Δp during ten months. The result is Table 1, which we now explain.

As is well known, the demand for energy responds slowly to price changes. Column 1 reports the short-run elasticity of demand after one, two and up to ten months, which was estimated by Benavente et al. (2005a); the long-run elasticity of demand is -0.39 . Next note that at the time of the shortage, residential customers paid \$136/MWh. Given those elasticities, each cell in columns 2–9 reports the fall in the total quantity of energy demanded for different values of $\$136/\text{MWh} + \Delta p$. For example, cell (7166) indicates that if the price of energy rises from \$136/MWh to \$166/MWh in month 0, consumers demand 2.5% less energy during months 1 through 5.²⁵ Similarly, cell (10,166) indicates that if the price of energy rises from \$136/MWh to \$166/MWh in month 0, consumers demand 3.1% less energy during months 1 through 10. Now, as said before, a fall of only 2.5% of total consumption would have been enough to avoid outages. Table 1 thus says that an increase of just \$30/MWh of the BT1 residential tariff would have been enough to achieve that proportional reduction from residential customers by month 7 of the shortage.

There are no estimates of the elasticity of the demand for energy of non-residential customers and we cannot produce the equivalent of Table 1 for that category. But in any case we can calculate an upper bound of the cost of an efficient restriction by assuming that all the restrictions is borne by residential customers.²⁶ As said, a reduction of 6% of residential consumption would have been enough to reduce total energy consumption by 2.5% between September 1998 and June 1999. Column 8 in Table 1 indicates that raising the BT1 residential tariff to \$206/

²⁴ Benavente et al. (2005b) estimate that in Chile the per-kWh cost of outages is about three to six times larger.

²⁵ Consequently, Table 1 reports the monthly average fall in the quantity demanded. Because the price elasticity increases over time in absolute value, consumption in the last month falls by more than the average.

²⁶ Rationing only residential customers may be politically costly for a regulator. Hence our exercise is merely illustrative. Note, however, that a profit-maximizing retailer would look for those kWh that are the cheapest to reduce among all customers, not only residential ones.

Table 1
Fall of residential electricity consumption (in %; initial tariff: \$136/MWh).

\$/MWh → Month ↓	(1) η	(2) 146	(3) 156	(4) 166	(5) 176	(6) 186	(7) 196	(8) 206	(9) 216
1	-0.055	0.4	0.7	1.1	1.4	1.7	2.0	2.2	2.5
2	-0.073	0.5	0.9	1.3	1.6	2.0	2.3	2.6	2.9
3	-0.108	0.6	1.1	1.6	2.0	2.4	2.8	3.2	3.6
4	-0.129	0.6	1.2	1.8	2.3	2.8	3.3	3.7	4.1
5	-0.155	0.7	1.4	2.0	2.6	3.2	3.7	4.2	4.7
6	-0.174	0.8	1.6	2.3	2.9	3.5	4.1	4.7	5.2
7	-0.194	0.9	1.7	2.5	3.2	3.9	4.5	5.1	5.7
8	-0.211	1.0	1.9	2.7	3.5	4.2	4.9	5.5	6.1
9	-0.227	1.0	2.0	2.9	3.7	4.5	5.2	5.9	6.6
10	-0.242	1.1	2.1	3.1	3.9	4.8	5.5	6.3	7.0

Note: Long-run elasticity = -0.39; short-run elasticity in column 1.

MWh ($\Delta p = \$60/\text{MWh}$) would have reduced residential consumption by 6.6% over nine months, enough to prevent rationing. It follows that the cost of an efficient restriction would have been smaller than

$$(p_e^r + \Delta p) \times (D(p_e^r) - E_r)$$

or

$$450,000 \text{ MWh} \times \$206/\text{MWh} = \$92.7 \text{ million,}$$

about 40% of the cost of proportional rationing.

Note that our back-of-the envelope calculation overestimates the cost of an efficient restriction, because the BT1 residential tariff is an energy-only levelized tariff; customers who pay separate charges for energy and capacity (see (2.2)), and who are entitled to receive compensations, pay about 40% less for energy, and hence the cost of reducing consumption at the margin is far smaller. Moreover, an efficient load shedding scheme would reduce energy consumption during months such that the spot price exceeds the node price by a substantial amount.

The effectiveness of such a scheme depends on the magnitude of the elasticity of demand. In Appendix B we report the equivalent of Table 1 for three alternative long-run elasticities: -0.1, -0.7 and -1. Only with very small price elasticities is such a scheme ineffective to deal with shortages. Many studies, by contrast, obtain elasticities which are even larger than Chile's. For example, Espey and Espey (2004) survey 36 studies that estimate the residential demand for electricity. They report that estimates for the long-run price elasticity run from -2.25 to -0.04, with a mean of -0.85 and median of -0.81. Furthermore, in Table B.2 in Appendix B we report estimated price elasticities from 33 studies; most are well above the estimate of Benavente et al. (2005a, 2005b). Last, the Lawrence Berkeley National Lab at the University of California undertook several studies in recent years showing that customers respond to price changes—see Heffner and Goldman (2001), Goldman et al. (2002), Siddiqui et al. (2004) and Reiss and White (2003).

3.2. Gas shortages and rigid prices

3.2.1. The Argentine gas cuts

Between 1998 and 2004 capacity expanded mainly with combined-cycle turbines fueled with natural gas imported from Argentina. But when gas cuts began in May 2004 the Argentine government announced that it would not grant any further export permits in the foreseeable future, a clear violation of the protocol it had signed in 1995. Worse, protracted and increasing gas cuts ensued, as shortages in Argentina, which were caused by the price controls introduced in the aftermath of the 2001 devaluation, worsened.

In a standard market a supply shock like the loss of Argentine gas would have sharply increased the short run equilibrium price of electricity. Then, at some point, investors would have been willing to invest in coal plants, the fossil fuel that had been displaced by Argentine natural gas in the late nineties. Of course, one risk of investing in coal is that natural gas may return in the future if the Argentine government lifts price controls—natural gas is cheap and abundant in Argentina and pipelines that cross the Andes mountains are still there. But in a normal market that risk is either paid for with higher equilibrium prices or hedged with long-term contracts such that customers assume part of the risk that natural gas imports will resume at some point in the future. Neither alternative was available in Chile.

On the one hand, distributors had to contract at the node price, which varies every six months—they could not assume a long-term commitment to pay prices determined by the cost of coal. On the other hand, the regulated energy node price was capped by the band. As a consequence, investment ground to a halt and the probability of a shortage sharply increased.

The government reacted fast, and the Chilean congress amended the law in May 2005. The band was widened and prices were allowed to rise much faster.²⁷ As a result, consumption growth slowed, generators installed many diesel turbines and a shortage was prevented. Moreover, as we already mentioned, auctions of long-term contracts substituted for the regulated node price; this applies for new contracts between generators and distributors. This, it was thought, would allow investment in coal plants to resume. But here weak incentives wrought by regulated retailing became apparent.

The law states that each auctioned contract must be approved by NEC before being put to tender. But NEC also had to issue a so-called resolution, which spells out the rules that distributors must follow when auctioning regulated contracts. Despite the urgency, it took NEC almost a year to write the preliminary rules. Only in July 2006 were the first tenders called and the first contract was allocated in November 2006, almost a year and a half after the law was amended. As a consequence, several coal investments were delayed at least by a year.

3.2.2. An estimate of the costs of the delay

We now provide an estimate of the cost of the delay. Note that generators coped with the gas shortage by running their combined-cycle gas plants with diesel, and by installing small diesel open cycle gas turbines. At the time, each MWh generated with diesel cost \$190/MWh. Coal plants, on the other hand, would generate each MWh at about \$40/MWh. Hence, anticipating the entry of coal plants would have substituted coal for diesel almost

²⁷ See the Appendix in Galetovic and Muñoz (2009) for details.

one to one at the margin, and had a benefit of
 (\$190/MWh–\$40/MWh) × (MWh generated with coal)
 –additional capital costs.

Now had contracts been auctioned one year before, the 135 MW Guacolda 3 station and the 242 Ventanas 3 stations would have been available at least one year before.²⁸ Hence, assuming an 80% plant factor, 2642 GWh would have been generated with coal and \$396.3 million would have been saved in operation costs.²⁹ Last, anticipating investments by one year would have added \$73.7 million in capital costs.³⁰ Hence, by this estimate total savings would have been \$322.6 million.

Our calculation overlooks the exact timing of entry and ignores that the pattern of fuel substitution depends on the hydrology – during very wet years, diesel plants run less – and on the use of water in the Laja reservoir. To check the robustness and accuracy of our back-of-the-envelope calculation we run the Omsic model, which optimally uses water in the Laja reservoir to minimize the expected cost of generation and outage and considers the stochastic nature of hydrologies in Central Chile.³¹ Results are presented in Fig. 5.

It can be seen that savings in operation costs are spread over four years – respectively, \$137.5 million in 2008; \$245.5 million in 2009; \$51.8 million in 2010; \$35.4 million in 2011 – and disappear on the fifth. They stretch two years beyond 2009 because the anticipated entry of coal plants would have altered the use of water in the Laja reservoir. With a 10% discount rate, this is equal to \$430.1 million in present value. Subtracting increased capital costs, this yields net savings of \$356.4 million. Moreover, as can be seen by comparing MC base with MC anticipated, marginal costs would have fallen, especially in 2009, where they fall from \$124/MWh to \$94/MWh.

NEC argued that its delay was irrelevant, because no generator announced any projects between May 2005 and October 2006. But this ignores that financiers require generators to produce a contract as a condition for closing financing. At the same time, distributors did not show any urgency, as they had nothing to gain or lose—they just pass through the winning bid.

3.3. Market power and tariff inefficiency

3.3.1. The problem

As we already said, most regulated customers pay the BT1 residential tariff, a levelized price. Although the BT1 tariff is in principle calculated to ensure that total payments received by the distributor equals its costs, the levelized price distorts incentives at the margin.

The distortion can be appreciated with the help of a simple example and Fig. 6. Assume that the demand for capacity is $\overline{AD}(p)$ during a fraction $1 - \alpha$ of the 8.760 h of the year and $\underline{A} \cdot \overline{D}(p)$ for a fraction α of the rest, with $\overline{A} > \underline{A}$ and large enough, so that there is no peak reversal. In that case, it can be shown that the price of energy should be p_e^r during off-peak hours. By contrast, during peak hours the price of energy should be

$$p_T^r \equiv p_e^r + \frac{\psi p_c^r + \delta VAD}{\alpha 8760}$$

²⁸ Guacolda 3 in September 2008 instead of September 2009; Ventanas 3 in January 2009 instead of January 2010.

²⁹ $377 \text{ MW} \times 8.760 \text{ h} \times 0.8 = 2642 \text{ GWh}$; $2642 \text{ GWh} \times \$150/\text{MWh} = \$393.6$ million.

³⁰ This assumes that coal plants cost \$2300/kW and that the discount rate is 10%.

³¹ Until recently Omsic was used to run the actual dispatch of plants in Chile. A thorough description of the model is in the appendix of Galetovic and Muñoz (2009), where we refer the interested reader.

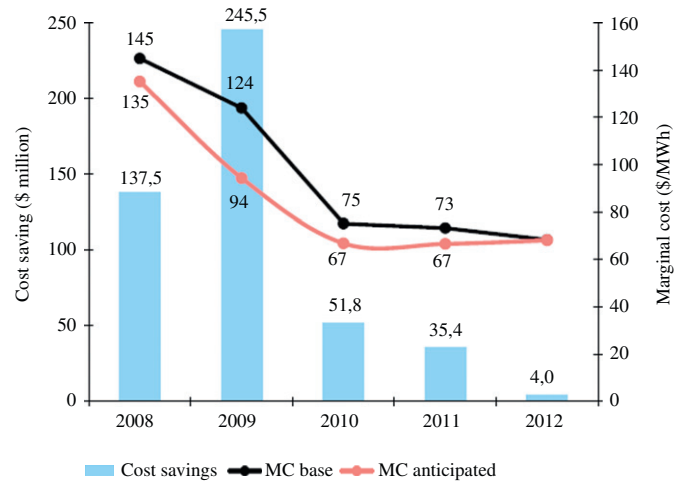


Fig. 5. Cost of delaying contract auctions.

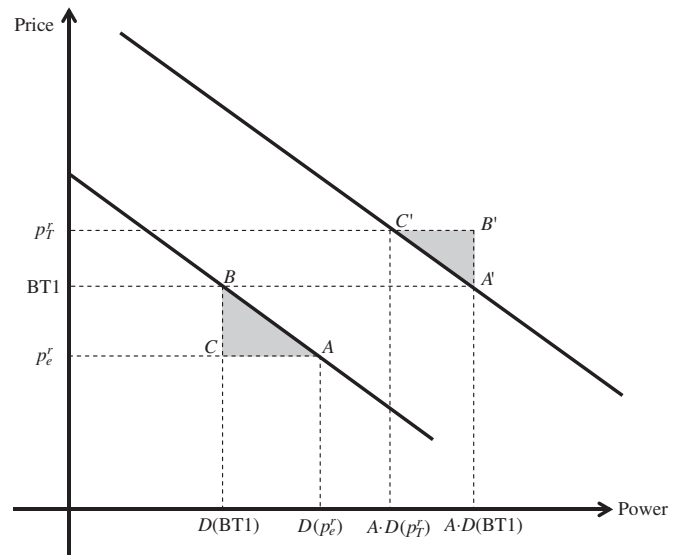


Fig. 6. Social cost of a levelized tariff.

Note that if there are many indistinguishable hours such that the demand for capacity peaks ($\alpha 8760$ in our example), then the capacity charge is paid as an energy charge.

Now because the BT1 tariff is set to pay for energy, capacity and distribution, and prorates capacity charges over the 8.760 h of the year, it follows that

$$p_e^r < BT1 < p_T^r$$

Moreover, the no peak reversal assumption implies that

$$\underline{AD}(p_e^r) < \overline{AD}(p_T^r)$$

The consequences of the levelized BT1 tariff can be appreciated in Fig. 6. During each off-peak hour customers use too little electricity, and the welfare loss is equal to the triangle ABC. By contrast, during peak hours too much electricity is consumed, and the welfare loss is triangle A'B'C'. Hence, the total loss is

$$8.760 \times [(1 - \alpha)ABC + \alpha A'B'C']$$

In addition, the distributor has strong incentives to exaggerate the load-coincidence factor ψ and the responsibility factor δ in formula (2.3) because tariff regulation restrains monopoly power. If successful, this adds to the burden of the levelized tariff. In what follows we report our estimation of the social loss wrought by distorted pricing and the excess price paid by regulated customers.

3.3.2. An estimate of the costs of inefficient pricing

To gauge the order of magnitude of the distortion, we have approximated the empirical load curve of customers who pay the BT1 tariff with a 12-block load curve.³² Then we estimated the optimal differentiated charge and calculated the welfare change (see the details in Appendix A).

The dark line in Fig. 7 shows the load curve of residential customers paying the BT1 tariff. In 2009 BT1 customers will use 13,600 GWh of energy and about 2,500 MW on the peak block, which lasts 1,460 h.³³ This yields a load factor of about 62%. As a reference, consider that in October 2009 the energy node price was \$138/MWh, whereas the BT1 tariff charged by Chilectra, the distribution company in the capital city of Santiago, was \$210/MWh—i.e. about 65% of the tariff paid for energy.^{34, 35}

To study the effect of a differentiated tariff we assume that the long-run price elasticity of the residential demand for electricity is -0.39 in Chile, as estimated by Benavente et al. (2005a, 2005b).³⁶ Then it can be shown that, subject to the distributors' self financing constraint, charging \$272/MWh during the first two blocks (which last 1,946 h) and \$138/MWh, the node price, during the rest of the 8,760 h of the year, maximizes social welfare. As can be seen in Fig. 7 and Table 2, such pricing reduces capacity use by 241 MW (or 10%) during peak hours, and increases it by 18% during off-peak hours. As a consequence, total yearly energy consumption increases from 13,601 GWh to 14,737 GWh (or 8.4%), and the load factor rises from 62% to 75%.

Table 2 also shows the changes in distributor's revenues and costs, and in consumer surplus. Distributor revenues fall by \$254 million, or 8.9% because consumers pay much less during off-peak hours. Indeed, the average price of each MWh sold falls from \$210 (the BT1 tariff) to \$177. Because total costs rise by \$96 million, distributors' profits fall from \$350 million to zero. Consumers, on the other hand, gain \$417 million, partly because they pay less (\$254 million) and partly because consumer surplus increases by \$163 million. All in all, social welfare increases by \$67 million a year.

Note that consumer gains are about an order of magnitude larger than the increase in social welfare (\$417 million against \$67 million). This occurs because the current BT1 tariff is too high, and distributors make economic profits. In other words, distributors seem to be successful in convincing the regulator that customers' load and coincidence factors are lower than what they really are. This suggests that it should not be assumed that regulated retailing will pass through the average spot price as a matter of course, and confirms Littlechild's (2000, 2002, 2003) arguments that liberalizing retailing may be necessary to endure that small customers pay competitive prices.

The magnitude of the social gain depends on the price elasticity of demand. In Table 3 we report results with alternative price elasticities of demand: -0.1 , -0.7 and -1 . The more elastic the demand, the larger the increase in social surplus, consumer

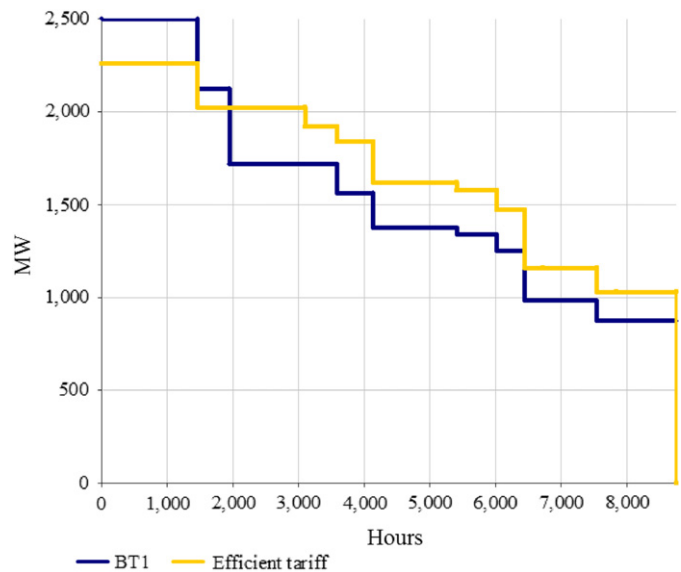


Fig. 7. Load curve of residential customers.

Table 2
The welfare gain of differentiated residential tariffs (in millions of dollars).

	(1) BT1 tariff	(2) Efficient tariff	(3) Change
Total revenue	2856	2602	-254
Energy purchases	1877	2034	157
Capacity purchases	629	568	-61
Total cost	2506	2602	96
Distributor profit	350		-350
Consumer surplus			417
Social surplus			67
Energy (GWh)	13,601	14,737	1136
Peak capacity (MW)	2499	2258	-241
Load factor	0.62	0.75	
\$/MWh			
Peak	210	272	62
Off-peak	210	138	-72
Average	210	177	-33

Note: Long-run elasticity = -0.39 .

surplus and load factor. In all cases, however, the order of magnitude of the gains is the same.

3.4. The modest cost of smart metering

Perhaps the main criticism of our assessment of regulated retailing is that some changes require smart metering, which many surmise to be too expensive. Nevertheless, a recent study by Rámila and Rudnick (2009) suggests that in Chile each smart meter would cost \$131.99 (including installation costs and IT support). On the other hand, each meter would generate operational annual savings of \$12.17 per unit. Assuming a real rate of discount of 10%, and that meters last 30 years, the net cost of a meter is only \$1.83 per year, or about 15¢ a month, equivalent to the price of 1 kWh. This is a modest charge that could be borne by almost any customer. In fact, customers who pay the BT1 tariff already pay about \$1 a month for the standard electromechanical meter. Thus, BT1 customers would pay slightly less for meters if smart metering is introduced.

In view of these numbers, it is telling that neither distributors nor the regulator has shown any interest in the massive installation of smart meters. Worse, regulators still allow distributors to

³² The load curve distinguishes: (i) between peak and off-peak season; (ii) between workdays and weekends within each season; and (iii) between low, medium and high consumption within each day. See the details in Appendix A.

³³ As of December 2008, there were 4,377,023 BT1 customers in SIC. Our estimate is based on increasing the consumption of BT1 customers in 2008 by the growth rate of electricity consumption in 2009.

³⁴ The alert reader will note that US\$138/MWh is considerably higher than any node price in Fig. 3. The reason is that the node price in Fig. 3 is at a specific high-voltage node (Quillota) where power is injected by a generator. On the other hand, the node price paid by the customers of Chilectra includes transmission, distribution and transformation losses.

³⁵ Note that the node price is independent of downstream tariff structure and levels because dispatch is mandatory and in strict merit order. For this reason, assuming an exogenous node price is a sensible first approximation.

³⁶ Benavente et al. (2005a) estimated the price elasticity of demand with a panel of distribution companies between 1995 and 2006. Agostini and Saavedra (2009) obtained an identical estimate with data of the Casen household survey.

Table 3
The welfare gain of differentiated residential tariffs with different price elasticities of demand (in millions of dollars).

	(1) BT1 tariff	(2) $\eta = -0.1$	(3) $\eta = -0.39$	(4) $\eta = -0.7$	(5) $\eta = -1$
Total revenue	2856	2521	2602	2727	2852
Energy purchases	1877	1916	2034	2143	2256
Capacity purchases	629	605	568	584	596
Total cost	2506	2521	2602	2727	2852
Distributors' profits	350	0	0	0	0
Δ in consumer surplus	–	372	417	432	450
Δ in social surplus	–	22	67	82	100
Energy (GWh)	13,601	13,888	14,737	15,528	16,345
Peak capacity (MW)	2499	2403	2258	2318	2366
Load factor	0.62	0.66	0.75	0.76	0.79
\$/MWh					
Off-peak	210	138	138	138	138
Peak	210	310	272	234	222
Average	210	182	177	176	174

charge between \$7 and \$18 a month for obsolete electromechanical meters able to measure peak loads. Indeed, this is another example of the costs of regulated retailing.

4. Conclusions

In his assessment of electricity market liberalizations around the world, Joskow (2008) asks whether retail competition is worth the trouble compared to a regime where the distribution company procures power competitively and resells it at cost to residential and small commercial customers. We have taken a close look at regulated electricity retailing in Chile and found that it has significant shortcomings. Distributors have been slow to adopt smart meters and the regulator still allows them to charge high rental prices for obsolete meters. Moreover, failure to improve tariffs makes the Chilean system vulnerable to droughts, inflexible to supply shocks like the Argentine gas cuts, and hurts residential customers, who pay inflated prices for energy.

Of course, one can always attribute Chilean defects to Chilean incompetence—perhaps regulated retailing is a great idea, it only takes clever regulators to make it work. Nevertheless, incompetence is a rather unconvincing explanation, because Chile has been at the forefront of electricity reform. Moreover, in Chile regulated prices are effectively a pass through of the energy and capacity price determined in the wholesale market. Last, and more fundamental, regulated retailing is almost inevitably a choice of one or at most a few points in the risk-allocative efficiency tradeoff. In principle, this can always work, and any new shortcoming that emerges can be dealt by swiftly and deftly improving regulations. In practice, however, regulated retailing is rigid and won't adapt fast enough to unforeseen contingencies.

Whether the liberalization of retailing realizes these benefits is an open question and depends on the costs of liberalized retailing, the intensity of competition, and the scope for innovation in selling electricity. But while not necessarily proving the case of liberalized retailing, the deficiencies we have detected cast doubt on the basic premises of the market policy approach and on the practical feasibility of efficient pricing with regulated electricity retailers.

Appendix A. Estimating the distortion wrought by the BT1 tariff

In this appendix we explain how we obtained the estimates in Table 2.

Step 1: the load curve We start by approximating the empirical load curve of residential customers. Our curve distinguishes: (i) between peak months (April through December) and off-peak months (January through March); (ii) between workdays and weekends; and (iii) within each day between low consumption (7 h), medium consumption (8 h) and high consumption (9 h). Thus we have 12 demand blocks.

Step 2: demand Within each block we assume that the hourly demand curve is the same. Let p be the price, q the quantity demanded at a given hour and η the price elasticity. We assume that the demand during each hour in block $k \in \{1, 2, \dots, 12\}$ is

$$q_k = A_k p_k^\eta.$$

Hence, if h_k is the total number of hours with block k , the total energy consumed during block k is

$$e_k = h_k q_k = h_k A_k p_k^\eta.$$

Note that our demand function assumes that there is no substitution across hours—consumption during a given hour does not depend on the prices during other hours.

Step 3: recovering the A_k 's Now under current pricing residential customers pay the BT1 tariff and each hour in block k the quantity demanded is $A_k BT1^\eta$. We know this quantity from the load curve; we also know the BT1 tariff. Hence, we can recover the A_k 's and use them to simulate consumption under different pricing schemes. Without loss of generality, we assume that $A_1 \geq A_2 \geq \dots \geq A_{12}$; that is, in the first block (week day between April and December during the nine high-demand hours) demand is the highest.

Step 4: change in consumer surplus Now assume that the distributor charges $p_T^r > BT1$ during a given block k . Then consumption falls and consumer surplus in block k changes by

$$\Delta CS_k = h_k A_k \int_{BT1}^{p_T^r} p^\eta dp = h_k \frac{A_k}{1+\eta} \left[(p_T^r)^{1+\eta} - BT1^{1+\eta} \right]. \tag{A.1}$$

On the other hand, if the distributor charges the node price $p_e^r < BT1$, consumption increases in block k and the change in consumer surplus is

$$\Delta CS_k = h_k A_k \int_{p_e^r}^{BT1} p^\eta dp = h_k \frac{A_k}{1+\eta} \left[BT1^{1+\eta} - (p_e^r)^{1+\eta} \right]. \tag{A.2}$$

The total change in consumer surplus is

$$\Delta CS(p_e^r, p_T^r; BT1) \equiv \sum_{k=1}^{12} \Delta CS_k. \tag{A.3}$$

Table B.1

Short-run response of residential electricity consumption (in %; initial tariff: \$136/MWh).

US\$/MWh→ Month↓	(1) η	(2) 146	(3) 156	(4) 166	(5) 176	(6) 186	(7) 196	(8) 206	(9) 216
(a) Long-run elasticity = -0.1 (short-run elasticity in column 1)									
1	-0.014	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.6
2	-0.019	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.7
3	-0.029	0.1	0.3	0.4	0.5	0.6	0.7	0.8	0.9
4	-0.033	0.2	0.3	0.5	0.6	0.7	0.8	1.0	1.1
5	-0.040	0.2	0.4	0.5	0.7	0.8	1.0	1.1	1.2
6	-0.045	0.2	0.4	0.6	0.7	0.9	1.1	1.2	1.3
7	-0.050	0.2	0.4	0.6	0.8	1.0	1.2	1.3	1.5
8	-0.054	0.2	0.5	0.7	0.9	1.1	1.3	1.4	1.6
9	-0.059	0.2	0.5	0.7	1.0	1.2	1.4	1.5	1.7
10	-0.062	0.3	0.5	0.8	1.0	1.2	1.4	1.6	1.8
(b) Long-run elasticity = -0.7 (short-run elasticity in column 1)									
1	-0.098	0.7	1.3	1.9	2.5	3.0	3.5	4.0	4.4
2	-0.130	0.8	1.6	2.3	2.9	3.5	4.1	4.6	5.1
3	-0.193	1.0	1.9	2.8	3.6	4.3	5.0	5.7	6.3
4	-0.231	1.2	2.2	3.2	4.1	5.0	5.8	6.5	7.2
5	-0.276	1.3	2.5	3.6	4.7	5.6	6.5	7.4	8.2
6	-0.312	1.5	2.8	4.0	5.2	6.2	7.2	8.2	9.1
7	-0.347	1.6	3.1	4.4	5.7	6.8	7.9	8.9	9.9
8	-0.378	1.7	3.3	4.8	6.1	7.4	8.5	9.6	10.7
9	-0.407	1.9	3.5	5.1	6.5	7.9	9.1	10.3	11.4
10	-0.432	2.0	3.8	5.4	6.9	8.4	9.7	10.9	12.1
(c) Long-run elasticity = -1 (short-run elasticity in column 1)									
1	-0.141	1.0	1.9	2.8	3.6	4.3	5.0	5.7	6.3
2	-0.187	1.2	2.2	3.2	4.1	5.0	5.8	6.6	7.3
3	-0.278	1.4	2.7	3.9	5.1	6.1	7.1	8.0	8.9
4	-0.332	1.6	3.2	4.6	5.8	7.1	8.2	9.2	10.2
5	-0.397	1.9	3.6	5.2	6.6	8.0	9.2	10.4	11.5
6	-0.448	2.1	4.0	5.7	7.3	8.8	10.2	11.5	12.7
7	-0.499	2.3	4.4	6.3	8.0	9.6	11.1	12.5	13.9
8	-0.543	2.5	4.7	6.8	8.6	10.4	12.0	13.5	14.9
9	-0.584	2.6	5.0	7.2	9.2	11.1	12.8	14.4	15.9
10	-0.621	2.8	5.4	7.7	9.8	11.7	13.6	15.2	16.8

Table B.2

The elasticity of the demand for electricity.

		Short-run (one year)	Long-run
Australia	Woodland (1993)	-1.113	na
Canada	Elkhafif (1992)	-0.147	-0.697
CCEAG	Al Faris (2002)	-0.04/-0.18	na
Chipre	Zachariadis and Pashourtidou (2007)	na	-0.3/-0.4
Costa Rica	Westley (1989)	na	-0.45
Denmark	Bjørner and Jensen (2002)	-0.479	na
USA	Fisher and Kaysen (1962)	-0.15	na
USA	Houthakker and Taylor (1970)	-0.13	-1.89
USA	Anderson (1973)	na	-1.12
USA	Mount et al. (1973)	-0.14	1.2
USA	Houthakker (1962)	-0.89	na
USA	Houthakker et al. (1973)	-0.9	-1.02
USA	Dubin and McFadden (1984)	-0.197/-0.310	
USA	Westley (1988)	na	-0.99
USA	Chang and Hsing (1991)	-0.13/-0.36	-1.39
USA	Jones (1995): log-linear	-0.05	-0.207
USA	Jones (1995): trans-log	-0.276	-0.201
USA	Maddala et al. (1997)	-0.15/-0.21	-0.22/-1.03
USA	García-Cerrutti (2000)	-0.13	-0.17
USA	Reiss and White (2003)	-0.39	na
Finland	Ilmakunnas and Törmä (1989)	-0.73	na
Greece	Donatos and Mergos (1991)	-0.21	-0.58
Greece	Caloghirou et al. (1997)	0.51 (ind)	-0.77 (ind)
Holland	Boonekamp (2007)	na	-0.09/-0.13
Holland	Lijesen (2007): linear	-0.009	na
Holland	Lijesen (2007): log-linear	-0.03	na
India	Filippini and Pachuari (2002)	-0.16/-0.39	na
Israel	Beenstock et al. (1999)	-0.124 (res)	na
Israel	Beenstock et al. (1999)	-0.123 (ind)	na
Mexico	Bernd and Samaniego (1984)	na	-0.47
Nine European countries	Hesse and Tarkka (1986)	-0.14/-0.49	na
Paraguay	Westley (1984)	na	0.56
Switzerland	Brännlund et al., (2007)	-0.24 (res)	na
Taiwan	Holtedahl and Loutz (2004)	-0.15 (res)	-0.16 (res)
Three LDCs and USA	Roy et al. (2006)	na	-0.8/-1.76

We now describe the simulations.

Step 5: simulations Benavente et al. (2005a) estimate that $\eta = -0.39$. Moreover, in October 2009: (i) $BT1 = \$210/\text{MWh}$; (ii) $p_e^r = \$138/\text{MWh}$; (iii) the regulated price of capacity is $\$252/\text{kW}$ per year.

Now call Π the set of blocks such that $p_T^r > BT1$ is charged, and Π^c the set of blocks such that $p_e^r = \$138/\text{MWh}$ is charged. Note that there are

$$\sum_{j=0}^{12} \binom{12}{j}$$

combinations of (Π, Π^c) . For each we find the price p_T^r such that the distributors break even. And among these, we select the one that maximizes (A.3).

Step 6: results Last, our simulation estimates that $p_T^r = \$272/\text{MWh}$ charged in blocks 11 and 12 maximizes the increase in consumer surplus.

Appendix B

See Tables B.1 and B.2.

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